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ECONOMIC STUDY OF FUTURE AIRCRAFT FUELS (1970–2000)

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SUMMARY

The economics of liquid hydrogen, methane and propane as future aircraft fuels are examined and compared with present JP (kerosene) fuel over the time period 1970 to 2000. Resource availability, fuel processing methods and cost projections derived from numerous sources are discussed and compared for relative merit. The economic effects of various political scenarios on these factors are considered in order to elicit policy implications critically affecting national security and environmental quality.

INTRODUCTION

Currently, the United States imports about 23% of its crude oil, mostly from South America. Future U. S. petroleum demand (see figure 1) would indicate that by 1985 oil imports will constitute as much as 57% of our domestic oil needs. Much of this will have to be purchased through the newly formed Organization of Petroleum Exporting Countries (OPEC), a strongly nationalistic, militant combine of the North African and Persian Gulf countries. The political instability and intense nationalism of these nations raises serious questions as to the continuity of future oil and gas supply and price stability. Further, because of dwindling natural gas reserves, the U. S. is investing major capital (about $11 billion) in developing shipping capacity and port facilities to enable the import of liquefied natural gas (LNG) from Algeria and the recently proven North Atlantic fields. Again, the present hostile political policies of Algeria are not conducive to assurance of an uninterrupted supply of LNG. These are only a few examples of the types of problems which must be considered in analyzing future U. S. fuel requirements, sources and continuity of supply, prices and selection of processing methods.

This study was undertaken to evaluate future aircraft fuels as to fuel resource availability and pricing, processing methods, and economic projections over the period 1970-2000. In this paper, liquefied hydrogen, methane and propane are examined as potential turbine engine aircraft fuels relative to current JP fuel.

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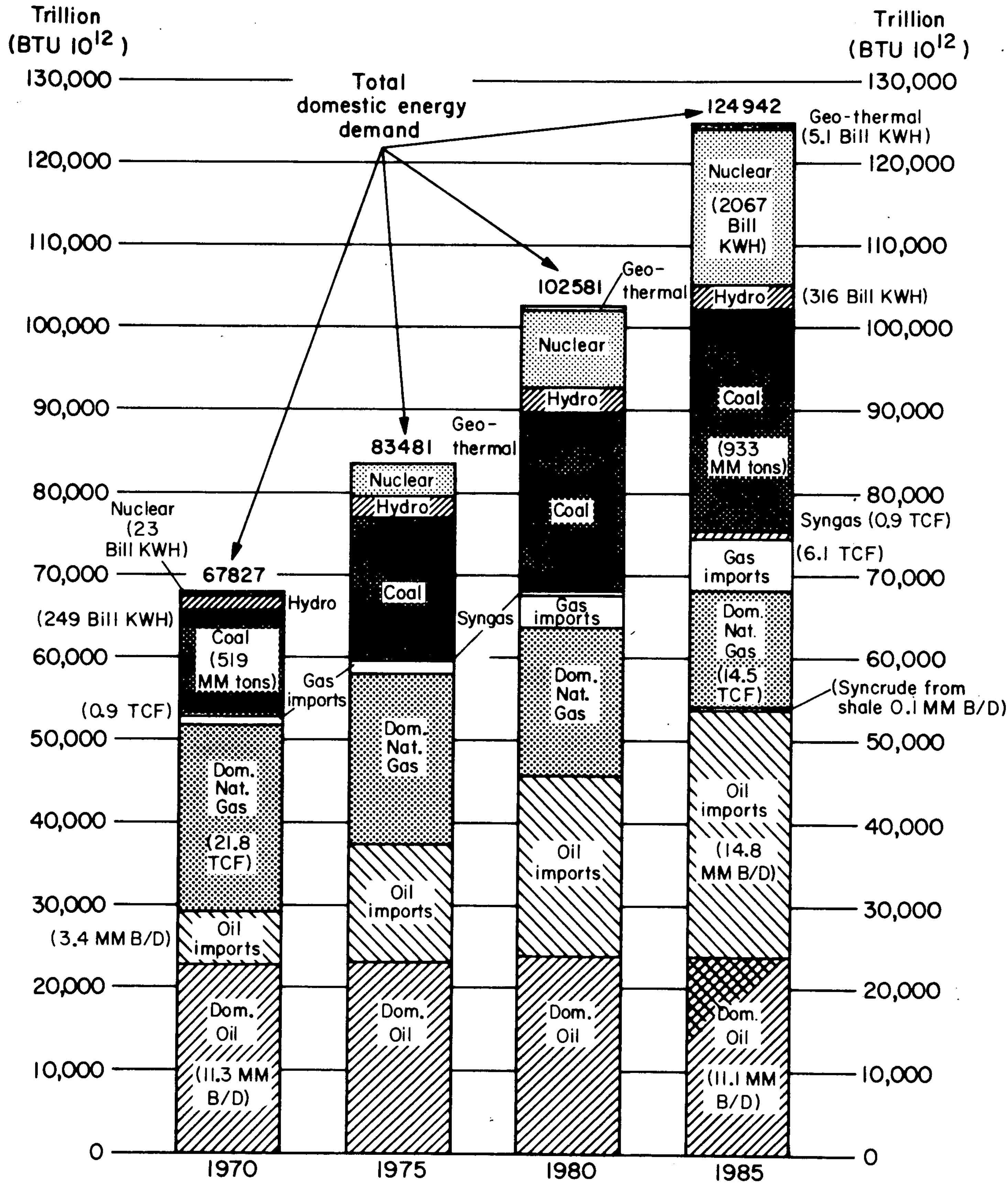

Figure 1.- U.S. Energy Balance - Initial Appraisal[1]

Source: "U.S. Energy Outlook - An Initial Appraisal, 1971-1985," National Petroleum Council, 1971.

ECONOMICS OF AVAILABLE RESOURCES

Both present and future aircraft fuels are most economically derived from petroleum and natural gas resources. Because aircraft fuels constitute a significant demand on these resources and directly reflect their pricing, economic studies of petroleum, and gas availability and pricing, are a natural precursor to an economic evaluation of future aircraft fuels.

U. S. Petroleum Supply, Demand and Pricing

U. S. domestic oil supplies (estimated by the National Petroleum Council[2]), consisting of crude oil, condensate and natural gas liquids, totaled 11.3 million barrels a day (B/D) in 1970, which was 31% of total U. S. energy consumption. As shown in figure 2, despite the addition of an estimated 2.0 million B/D from the Alaskan North Slope and another 2.7 million B/D from new discoveries to be made after 1970, total U. S. production in 1985 was estimated at only 11.1 million B/D. Therefore, in order to meet growing demands for petroleum liquids, imports would have to increase more than fourfold by 1985, reaching a rate of 14.8 million B/D in that year. Assuming the availability of foreign supply, oil imports would then account for 57% of total petroleum supplies and would represent 25% of total energy consumption. Most of the imports would have to originate in the Eastern Hemisphere because of the limited potential for increased imports from Western Hemisphere sources.

Domestic demand for the period 1985-2000 was projected at a uniform increase of 3% per year to a total of 40.5 million B/D in 2000. Domestic production (including North Slope) was estimated to decrease at an annual

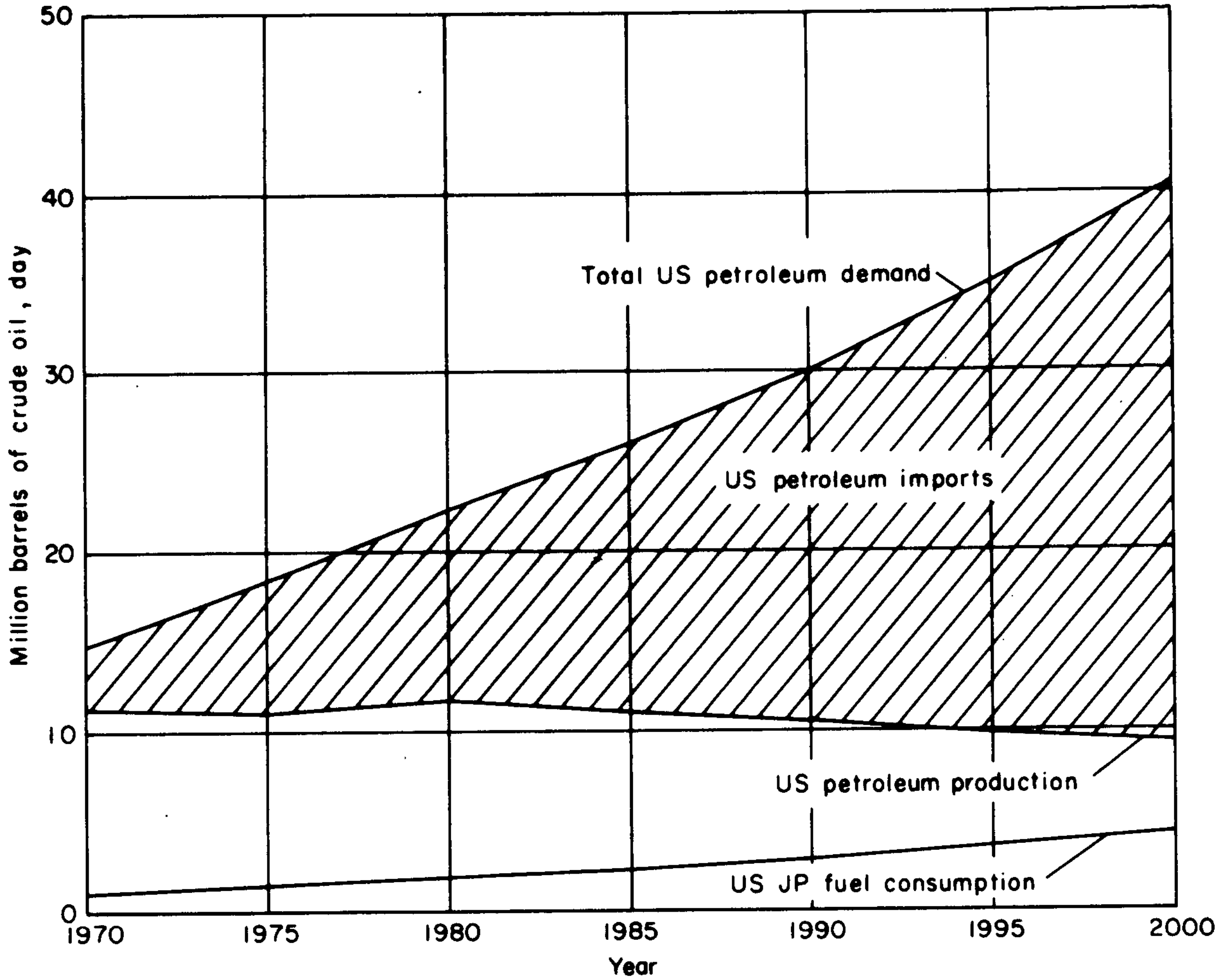

Figure 2.- U.S. Petroleum Supply/Demand (1970-2000).

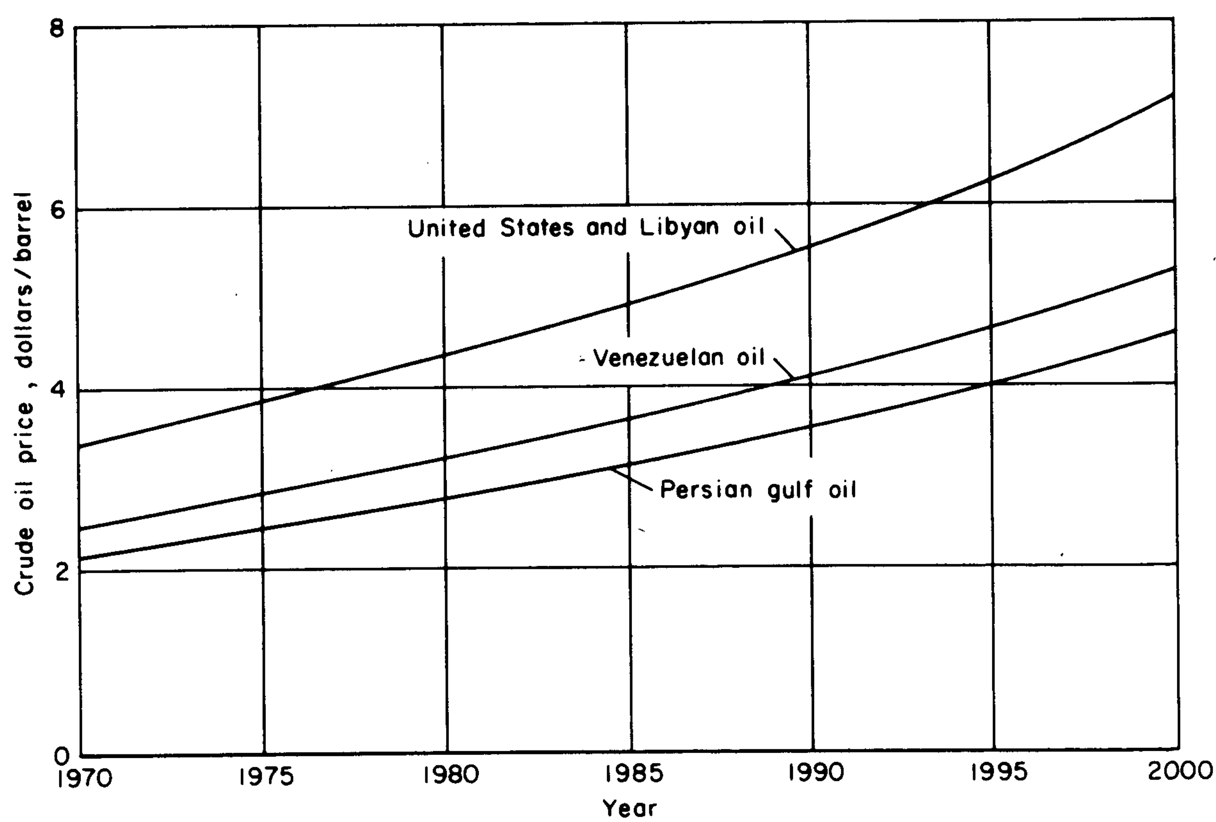

Figure 3.- Crude Oil Price Projections (1970-2000).

rate of about 1.5% to a total of 9.3 million B/D by the year 2000. If demand is to be met in the year 2000, foreign imports must supply 77% of U. S. oil consumption on the basis of present crude reserves. However, oil shale, tar sands and coal synthetic oil conversion processes can be expected to be competitively priced by the year 2000, and should constitute a major domestic source of petroleum.

In terms of 1970 dollars, the price of petroleum is expected to remain constant through the year 2000. The actual price of crude, subject principally to inflationary increases of about 2.5% per annum, is expected to rise from $3.40/bbl for Texas and Libyan crude and $2.15/bbl for Persian Gulf crude to $7.15/bbl and $4.50/bbl, respectively, by 2000 (see figure 3). During 1971, the OPEC showed no hesitancy in threatening a total embargo on oil exports if their price demands were not met during negotiations with the Western importers. This, in view of extrapolated shortages in western reserves, could result in sharply increased price demands up to the limit of existing synthetic oil prices.

United States Gas Supply, Demand and Pricing

United States demand for gas is expected to almost triple in the period 1970-2000 from a current annual level of 22.6 trillion standard cubic feet (TSCF) to a level of 63.4 TSCF in the year 2000.[3,4,5,6,7] Figure 4 illustrates future U. S. gas demand and sources of supply.

Discovery and development of new domestic gas reserves has been and will continue to be grossly inadequate to meet consumption demand for this clean, inexpensive fuel. The ratio of proved reserves to production of natural gas has dwindled from 20.2 in 1960 to 13.2 in 1970, which includes the Alaskan North Slope reserve. The natural gas situation is critical; many

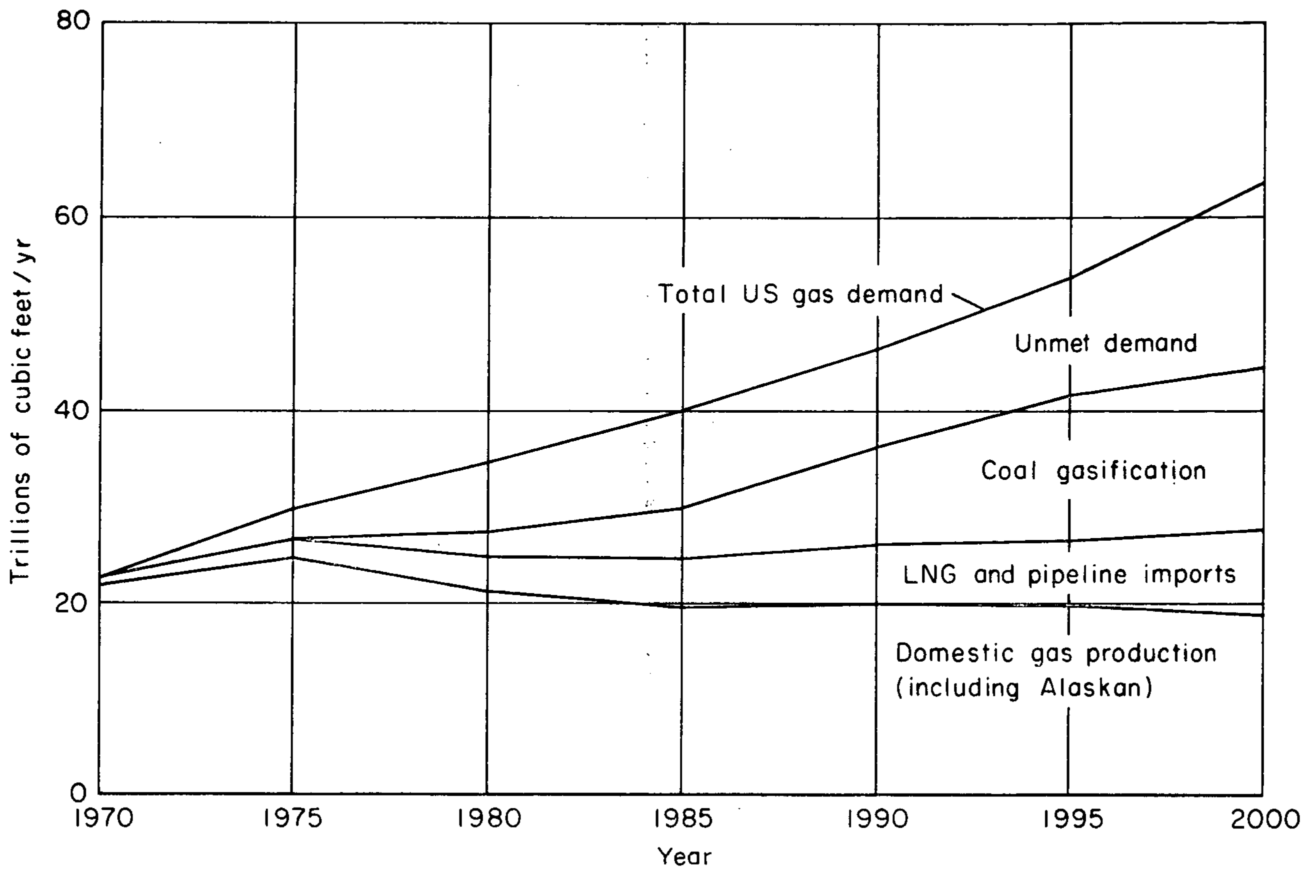

Figure 4.- U.S. Gas Demand (1970-2000).

distributors will not accept new customers because there are already peak load shortages and no promise of additional supplies.

The price of domestic natural gas at the wellhead and to the distributor (which includes pipeline delivery) has been projected in figure 5. The granting by the FPC of a 20% increase in the wellhead price of gas by 1975 is assumed in this projection. Thereafter, a 1.5% annual increase in the regulated wellhead price and a 2.5% inflationary increase in the pipeline cost has been assumed. In the timeframe 1970-2000, the wellhead price of gas is expected to increase from \$.169 to \$.320 per million Btu; the average distributor price is expected to increase from \$.674 to \$1.409

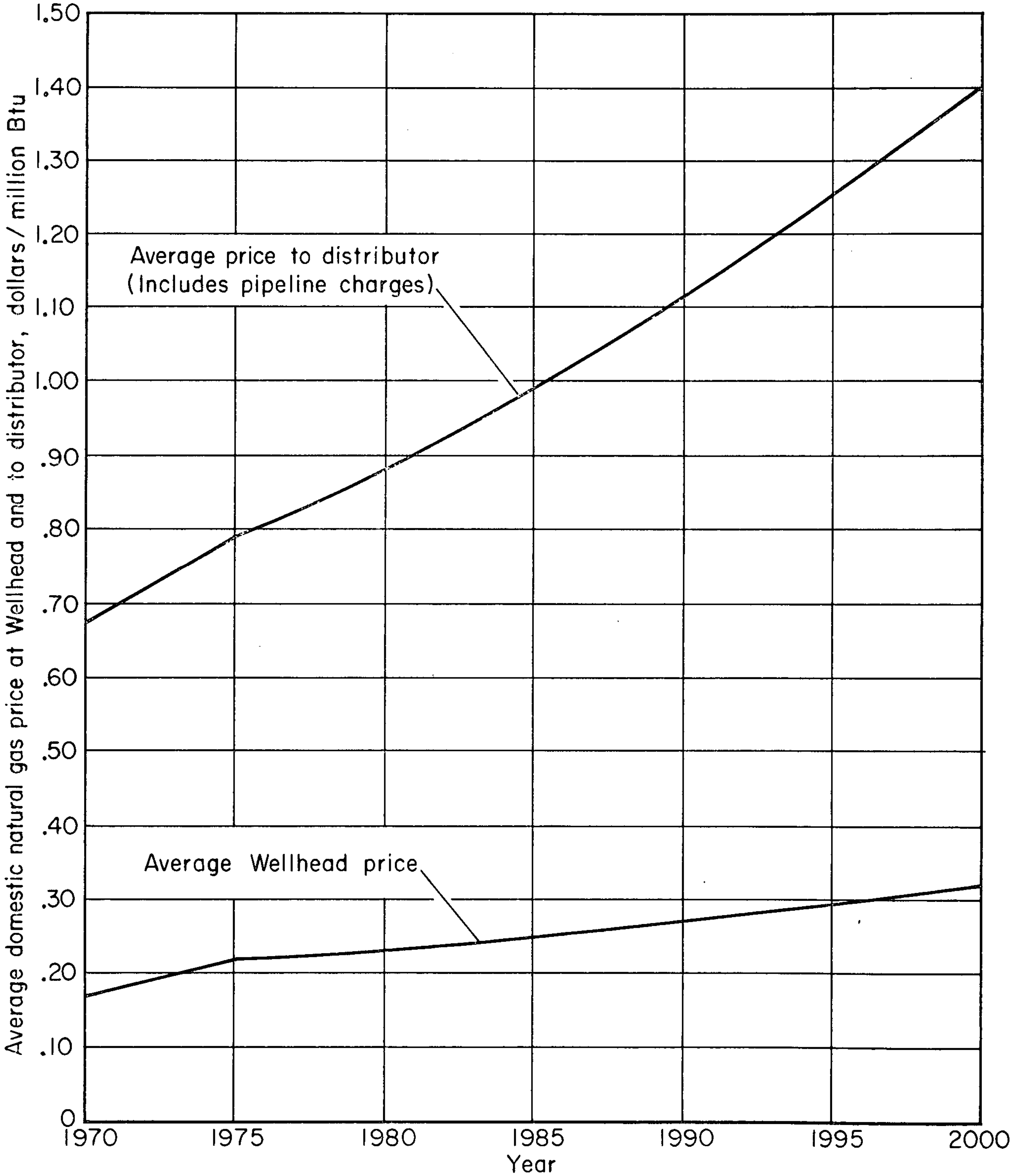

Figure 5.- Domestic Natural Gas Price Projection (1970-2000).

per million Btu. The latter price is largely a function of pipeline distance from wellhead to distributor. Even with this anticipated price increase, gas remains the least expensive, cleanest fossil fuel.

In order to supply the projected unmet U. S. demand for gas, many companies have petitioned the Federal Power Commission for major price increases to fund additional exploration, and to allow the import of liquefied natural gas from Algeria and the newly tapped North Atlantic reserves. Additional gas supply alternatives are the production of synthetic gas from coal gasification and catalytic/thermal cracking of petroleum. Several major western European countries have been using the Lurgi coal gasification process to successfully and economically meet their increasing gas needs.

Coal Gasification.- The economics and supply stability of obtaining synthetic gas through Lurgi coal gasification are very attractive. The resource is domestic coal; U. S. proved reserves are currently estimated at 394 billion tons.[8] Sixty million tons of coal (one-tenth of U. S. production in 1970) yields 1 trillion cubic feet of synthetic gas and 90 million barrels of synthetic crude oil. The gasification plant is built near the coal mine and nearer the user, reducing pipeline costs; there are about 176 potential plant sites in the U. S. Each plant costs about $209 million and is capable of processing 0.1 trillion cubic feet of gas and 9 million barrels of synthetic oil from 6 million tons of coal per year. The price[9,10] of the synthetic gas in 1970 dollars is $0.963 per million Btu as indicated:

5 (a)

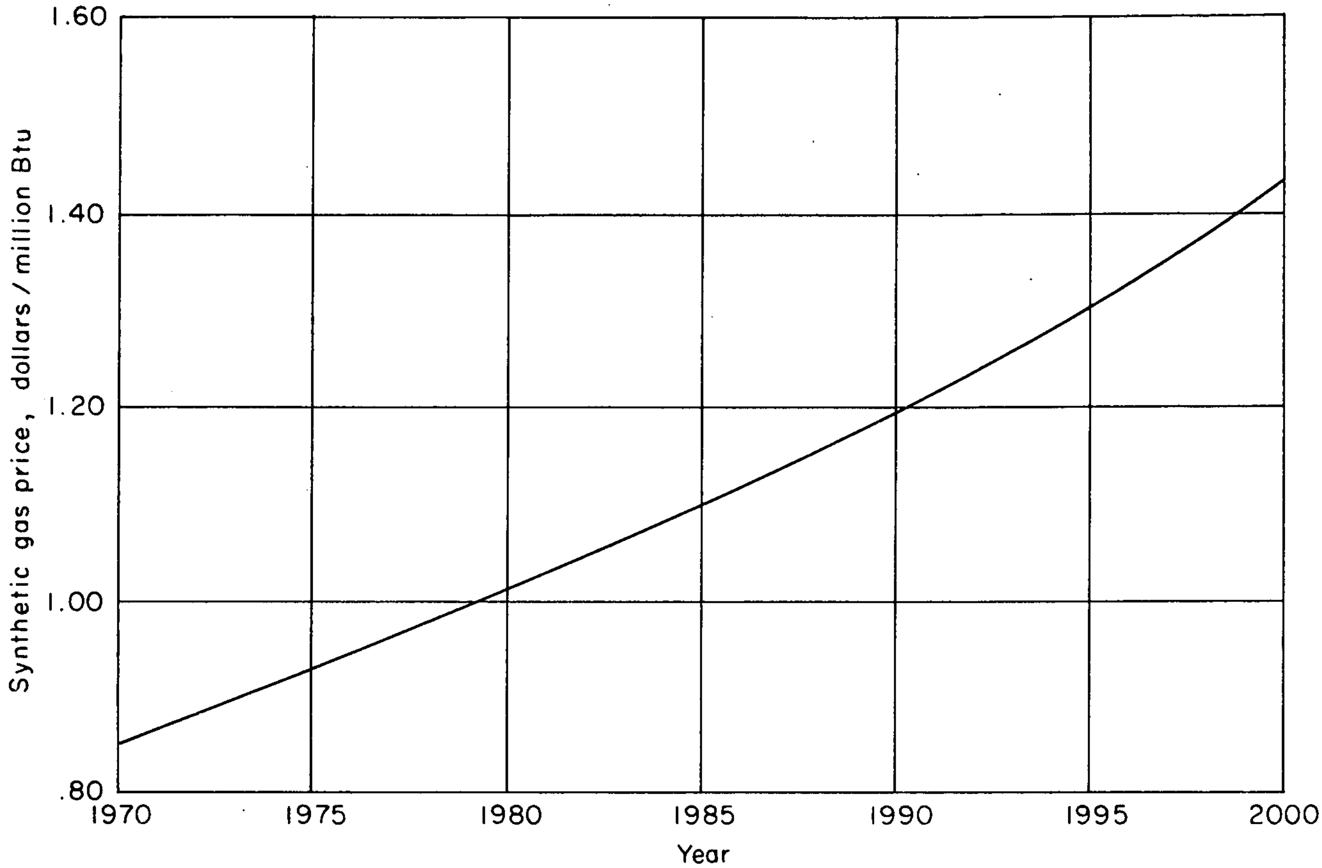

Figure 6.- U.S. Coal Gasification Price (1970-2000).

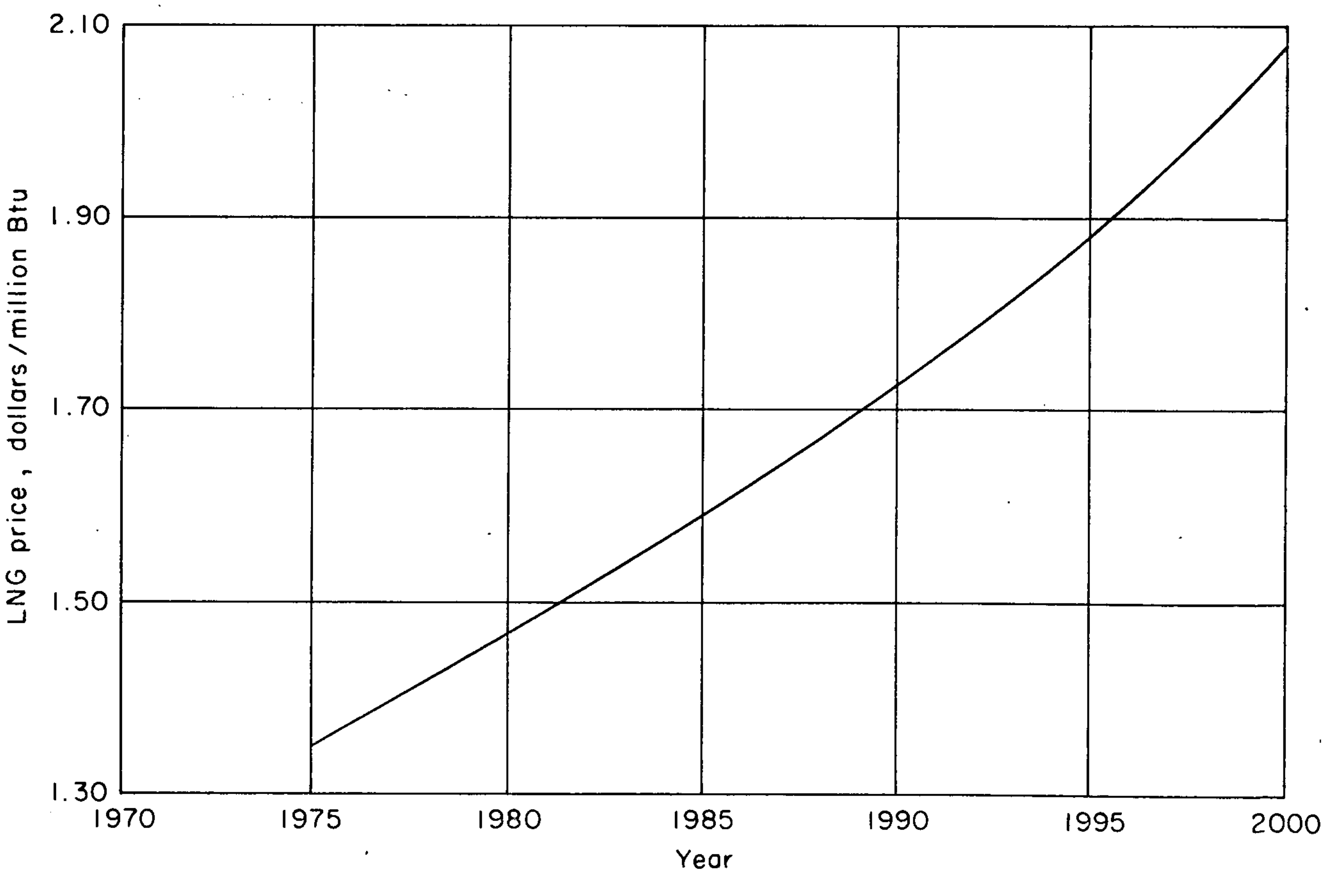

Figure 7.- Liquid Natural Gas (LNG) Import Price at U.S. Distributor.

1970 Price of Synthetic Gas from Coal

Cost Element	$Per Million Btu
Coal @ $.20/MM Btu (Western Strip)	.296
Operating Expense	.200
Capital Charge (22.2% on Initial Inv.)	.467
TOTAL COST FOB PLANT	.963

Advances in pilot design and process indicate the capital charge may be reduced by $.08-.12 per million Btu. Assuming a 2.6% inflationary price for coal and operating expenses, and a fixed capital charge of $0.367 per million Btu, figure 6 summarizes the projected price of synthetic gas from coal for the period 1970-2000.

Imported Liquefied Natural Gas (LNG).- By contrast, the importation of liquefied natural gas (LNG) from Algeria is far more expensive[11] at the distributor than coal gasification for equal volumes of gas and frought with problems both political and economic.

1970 LNG Price Per Million Btu at U. S. East Coast

Cost Element	$Per Million Btu
Algerian Gas	0.070
Liquefaction Expense	0.070
Plant Capital Charge (20% on $120 MM inv.)	0.240
Liquefied Gas FOB Plant	0.380
Ships Fuel	0.018
Port Charges	0.005
Ship Operating Expense	0.036
Ship Capital Charge (20% on $92 MM inv.)	0.184
Receiving Terminal Capital Charge (20% on $56.5 MM inv.)	0.113
Delivered LNG Price to U. S. (Landed Cost)	0.736

Regasification costs on East Coast and pipeline distribution costs to inland distributors adds an additional $.59 per million Btu to the landed cost of $.736. Figure 7 summarizes the projected cost of imported LNG at the distributor per million Btu (1970-2000).

Further, to supply 17.6 trillion cubic feet of gas by 2000, a capital investment of $46.9 billion must be made in LNG liquefaction, shipping and receiving facilities, 45% of which would be in foreign based liquefaction plants. To supply an equivalent volume of synthetic gas using domestic coal gasification would only require a cumulative capital investment of $36.6 billion (all in the U. S.) with assurance of a stable source of supply and investment security.

FUEL PROCESSING

Alternative technological processes are available for converting domestic coal into high-Btu-content, low-sulfur fuel oil or into high-Btu synthetic gas; urban and organic waste has been successfully converted into high-Btu-content fuel oil; and pilot processes are in development to extract petroleum from domestic tar sands and shale. This section attempts to describe the various alternative fuel processing technologies relevant to the subsequent analysis of projected aircraft fuel economics.

Petroleum Based Fuels

Processing to JP Aircraft Fuel.- Crude oil is desalted, dehydrated and heated to about 350°C prior to being pumped into a fractional distillation tower (see figure 8). The hot crude oil feed is mixed with 0.14-0.28 lb steam per pound of crude oil to aid separation of the fractions.

During distillation, the large crude oil molecules are fractionally split into volatile light gases including methane and propane which are drawn off from the top of the distillation tower. The heavier liquid fractions containing the naphthas, kerosene and gas oils are next drawn off, followed by the heavy lube oils. The kerosene is sent through a stripping column and subsequently blended with heavy gasoline fractions into the desired JP aircraft fuel. The liquid naphthas, containing most of the straight gasoline fraction (20% of crude oil volume) and gas oils are further cracked into smaller molecular fractions and fractionated to yield additional gasoline, light volatile gases, and fuel oils.

Processing to Hydrogen.- Most of the some 100 billion cubic feet of U. S. hydrogen produced annually is derived from petroleum refinery products: light refinery gases, gasoline, fuel oil and crude oil. The latter heavy molecular fractions are cracked to provide a high yield of the light gas fractions.

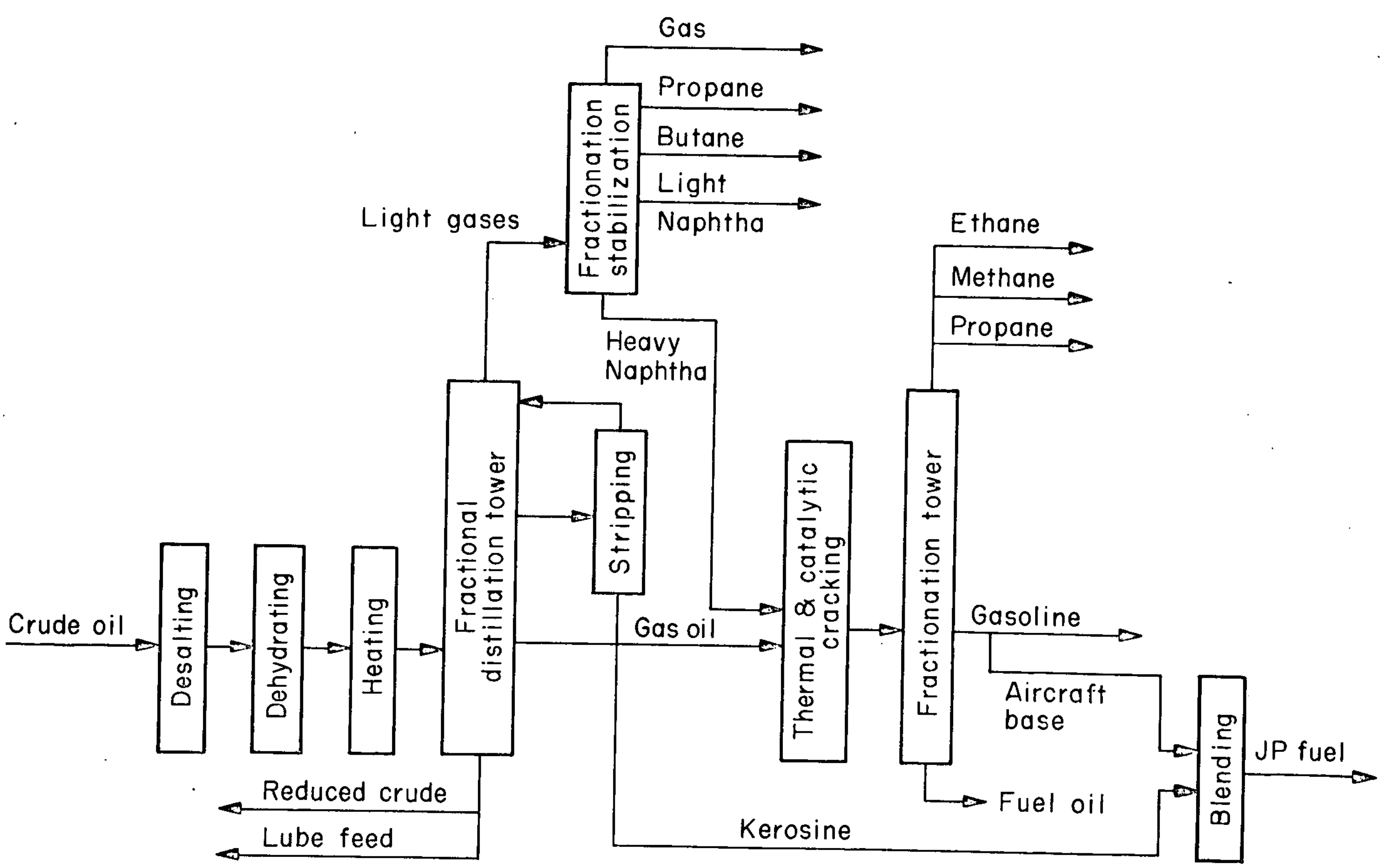

Figure 8.- Simplified Crude Petroleum Refining Flow Diagram.

Obviously, natural gas, rich in methane, is the preferred raw material source for hydrogen production, and petroleum light gases are a secondary source.

The light gas fractions are reacted with steam over a nickel catalyst at 700-1000°C to produce a mixture of carbon monoxide (CO) and hydrogen (H_2). The carbon monoxide is further reacted with steam at about 350°C over an iron catalyst to produce carbon dioxide (CO_2) and additional hydrogen.

The catalytic steam reforming reactions follow:

(methane)

$$CH_4 + H_2O \xrightarrow[\text{nickel catalyst}]{700\text{-}1000°C} CO + 3H_2 \; ; \; CO + H_2O \xrightarrow[\text{iron catalyst}]{350°C} CO_2 + H_2$$

(ethane)

$$C_2H_6 + 2H_2O \longrightarrow 2CO + 5H_2 \; ; \; 2CO + 2H_2O \longrightarrow 2CO_2 + 2H_2$$

(propane)

$$C_3H_8 + 3H_2O \longrightarrow 3CO + 7H_2 \; ; \; 3CO + 3H_2O \longrightarrow 3CO_2 + 3H_2$$

(butane)

$$C_4H_{10} + 4H_2O \longrightarrow 4CO + 9H_2 \; ; \; 4CO + 4H_2O \longrightarrow 4CO_2 + 4H_2$$

The carbon dioxide and hydrogen are normally separated by scrubbing with monoethylamine ($CH_3CH_2NH_2$).

Processing to Methane (CH_4) or Propane (C_3H_8).- The light volatile gases are derived from the distillation, cracking, reforming, fractionation and stabilization processes in crude oil refining. The mixed gases are processed to remove moisture, carbon dioxide and hydrogen sulfide. The main constituents of the dry gas are methane, ethane, propane, butane, ethylene and propylene. The methane, ethane, and propane fractions can be isolated by selective liquefaction taking advantage of the differences in boiling point among the mixture of gases.

Since the petroleum light gases have a high heating value (about 1500 Btu/ft^3), they are used extensively in refining operations and as a peak-load substitute for natural gas.

Should liquid methane or propane be required in substantial volume for aircraft fuel, the petroleum distillation, cracking and hydrogenation processes could be adjusted to yield a high fraction of the light gases. By analogy, straight crude oil distillation yields on the average only 20% gasoline; but, as gasoline demand increased, the larger molecular weight oils were cracked and fractionated to produce about a 50% yield of high octane gasoline. Additional light gas production from crude oil would require expansion of pretreatment and liquefaction capacity at most refineries.

Coal Based Fuels

Processing to JP Aircraft Fuel.- The U. S. Bureau of Mines[12] has developed a new process shown in figure 9 for providing a high yield of low-sulfur fuel oil from bituminous coal.

A high-sulfur bituminous coal suspended in coal tar was hydrodesulfurized by continuous processing through a fixed bed of pelletized cobalt molybdate on alumina catalyst, under conditions of highly turbulent flow of hydrogen to prevent obstruction of the flow of fluids and to promote catalytic contact. High yields of low-sulfur fuel oil were obtained. The feed contained 30% coal of 3.4% sulfur suspended in tar of 0.6% sulfur. For process conditions of 4,000 psig and 450°C, the yield of whole liquefied product was 94% of the whole feed; the product had 9% benzene-insoluble residues and only 0.3% sulfur. Most of the sulfur was in the insoluble residues and was organic. By separating the insoluble residues, the whole product gave a 91% yield of benzene-soluble fuel oil having only 0.09% sulfur. For the milder conditions of 2,000 psig and 450°C, the whole liquefied product was 93% of the feed and had 13% insoluble residues and 0.4% sulfur. By separating the residues, this product gave an 87% yield of fuel oil having only 0.14% sulfur. Commercially, part of the separated product oil would be recycled to suspend the feed coal instead of using the tar. Thus, the net product oil for fuel use would derive entirely from coal and is expected to have sulfur at least as low as reported above.

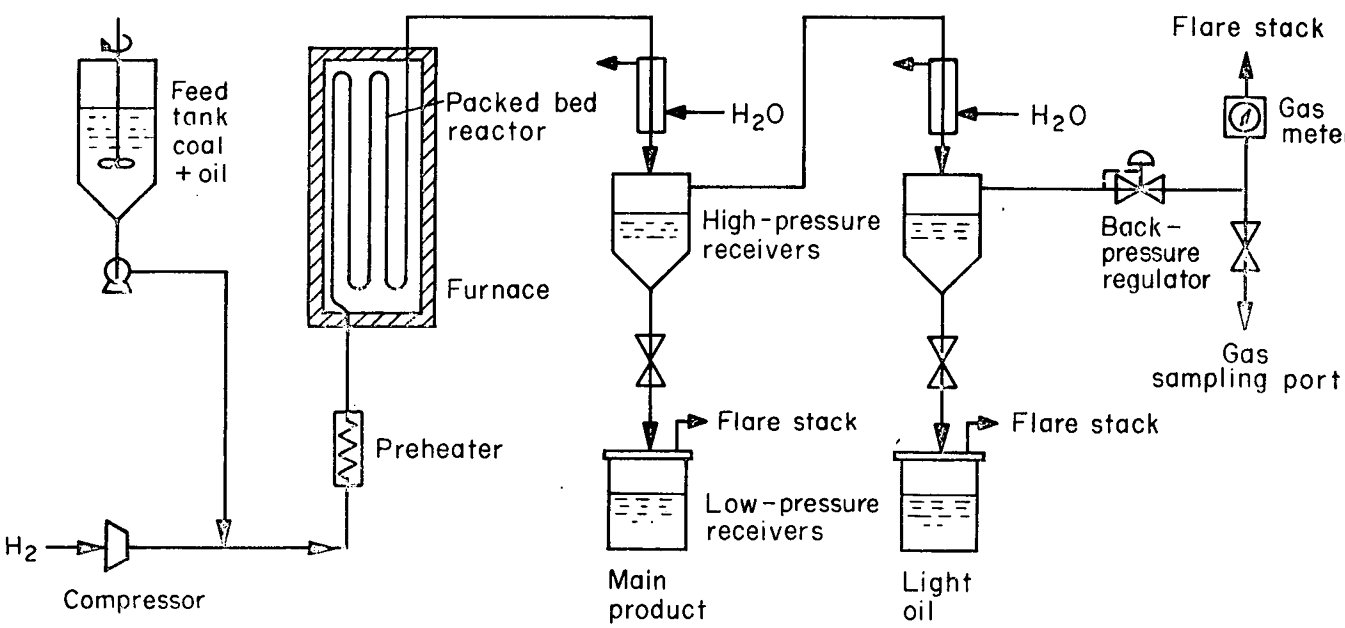

Figure 9.- Simplified Schematic Diagram of Hydrodesulfurization Pilot Plant.

The fuel oil product from coal could be hydrogenated and cracked to produce a lower molecular weight JP type fuel of reasonable octane rating.

Gasification to Hydrogen, Methane and Propane.- Because of its low nitrogen content, synthesis gas is the preferred product of initial coal gasification. The basic process is the Lurgi oxygen pressure gasification system shown in figure 10.

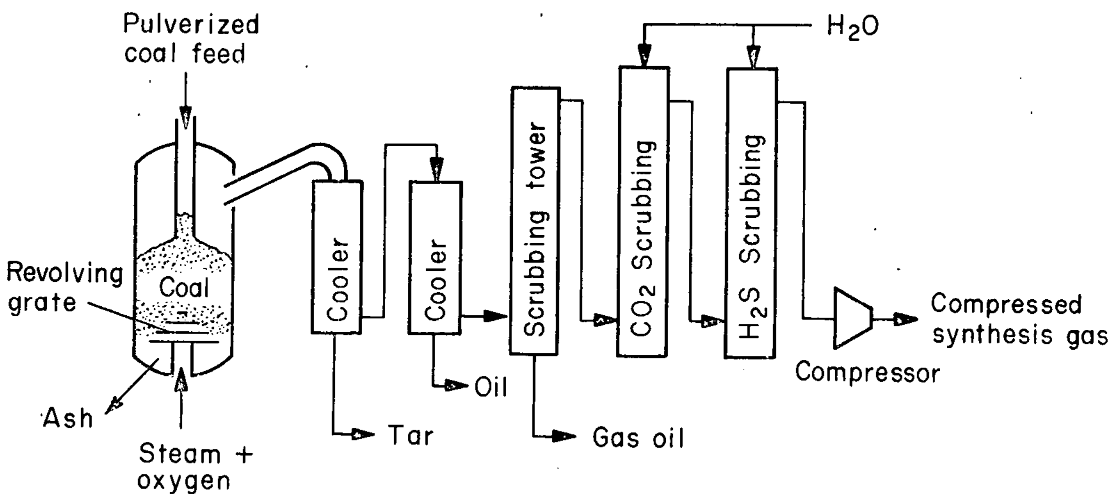

Figure 10.- Simplified Lurgi Coal Gasification Flow Diagram.

The basic reactions are:

(1) Coal (Hydrocarbon) Oxidation: $C + O_2 \rightarrow CO_2$

$$2H_2 + O_2 \rightarrow 2H_2O$$

(2) Reaction of CO_2 and H_2O with Carbon: $C + CO_2 \rightarrow 2CO$

$$C + H_2O \rightarrow CO + H_2$$

(3) Water Gas Shift: $CO + H_2O \rightarrow CO_2 + H_2$

(4) Methane Formation: $C + 2H_2 \rightarrow CH_4$ and $CO + 3H_2 \rightarrow H_2O + CH_4$

A typical coal synthesis gas will contain 50% H_2, 30% CH_4, 3% propane and butane, 8% CO, 1% CO_2, and 8% N_2. High pressure and temperatures less than 2000°F favor increased methane formation.

Modified Fisher-Tropsch processes convert desulfurized synthesis gas into hydrocarbon gases. The synthesis gas is hydrogenated over an iron or cobalt catalyst in a fixed-bed reactor operating at 200-400°C. The primary reactions are:

(1) $(n+1)\ H_2 + 2n\ CO \xrightarrow{\text{Fe catalyst}} (C_n\ H_{2n+2}) + nCO_2$

(2) $(2n+1)\ H_2 + n\ CO \xrightarrow{\text{Co catalyst}} C_n\ H_{2n+2} + nH_2O$

(These reactions are reversible at 1000°C:)

(3) $C_n\ H_{2n+2} + nH_2O \longrightarrow (2n+1)\ H_2 + nCO$

Thus both hydrogen and the C1-C4 gases can be produced from coal gasification.

Natural Gas Based Fuels

Processing to Methane, Propane and Hydrogen.- United States natural gas contains as much as 99.5% methane with traces of CO_2 and N_2. By definition, "wet" gas contains more than 0.1 gal of gasoline vapor per 1000 cu ft; "dry" contains less than 0.1 gal of gasoline. There are no olefins or hydrogen in American gas. European and African natural gas typically contains 35-85% methane, 35-10% ethane, 20-3% propane, 5-1% butane and 5-0% pentane.

These gas mixtures may be fractionally liquefied under pressure after scrubbing to separate the liquid components (gasoline, etc.) and the undesirable hydrogen sulfide, nitrogen and carbon oxides. Domestic gas is the least expensive source of methane.

Catalytic steam reforming of natural gas is the most economic source of bulk hydrogen. The reactions are:

$$C_n H_{2n+2} + nH_2O \xrightarrow[\text{nickel catalyst}]{700\text{-}1000\,^\circ C} [nCO] + (2n+1)\ H_2, \text{ and}$$

$$[nCO] + nH_2O \xrightarrow[\text{iron catalyst}]{350\,^\circ C} nCO_2 + nH_2$$

The hydrogen and carbon dioxide are separated by scrubbing with monoethylamine prior to hydrogen liquefaction.

Organic Waste Based Fuels

Processing to Aircraft Fuels (JP, H_2, CH_4, C_3H_8).- The U. S. Bureau of Mines developed a process[13] in 1971 for converting manure and other cellulosic wastes into a high Btu content fuel oil.

The cellulosic wastes may include urban organic refuse, agricultural waste (e.g., cornstalks, bagasse, etc.), sewage sludge, wood product waste, lignin and animal manures. The solid organic wastes generated in the U. S. in 1970 amounted to about 3 billion tons; enough to produce 1-1/2 to 2 billion barrels of oil by this conversion process. This is sufficient to supply nearly 50% of the 1970 U. S. fuel oil demand at an equivalent price.

The pulverized organic waste is continuously charged to a reaction vessel together with water and carbon monoxide in the presence of an alkaline catalyst such as sodium carbonate. The mixture is heated for about 20 minutes at 380°C and 2000-4000 psi pressure. The waste/oil conversion yield is about 90%. The product oil has a heating value of

15,000 Btu/lb and is composed almost entirely of aliphatic hydrocarbon analyzed as about 75% C, 9% H and 16% O.

Discussions with several major oil refiners indicated that the above product fuel oil could be upgraded through hydrogenation with existing process equipment to a suitable JP aircraft fuel.

Hydrogen could be produced through destructive distillation of the raw waste or by cracking the waste product fuel oil with subsequent steam reforming as described under the Petroleum Based Fuels section. Likewise, the C1-C4 aliphatic gases could be produced from fuel oil processing as discussed earlier.

Water Based Hydrogen

Processing to Hydrogen.- Electrolysis of sea water, $2H_2O \rightarrow 2H_2 + O_2$, generates hydrogen of very high purity (>99.9%) and high purity oxygen as a byproduct. Unless a large, inexpensive source of electricity is available, this is a very expensive way to produce hydrogen. Another less expensive process is to pass steam over iron catalyst at 800°C, $Fe + H_2O \rightarrow FeO + H_2$.

PROJECTED AIRCRAFT FUEL ECONOMICS (1970-2000)

The economics--supply, demand and pricing--of JP aircraft fuel (kerosene) and three potential aircraft fuels (liquid hydrogen, methane, and propane) are discussed in this section for the period 1970 to 2000. The economics of these four fuels are initially presented within the context of a "surprise-free" future; this future assumes:

(1) Resource exploration, discovery, development and usage trends will continue at present rates;

(2) Capital investment trends will continue at present rates;

(3) U. S. oil and gas imports will increase at present exponential rates;

(4) No significant restraints will be placed on U. S. oil and gas imports; and

(5) U. S. coal and nuclear power production will be expanded to maximum possible in this timeframe.

The economics of these four fuels are examined subsequently in the light of several likely, but pessimistic scenarios. The latter attempt to suggest national policy actions which could avert resource crises over the next 30 years; thus providing a more stable, secure energy future in the United States.

Surprise-Free Future

JP Aircraft Fuel Economics.- The projected U. S. demand for JP aircraft fuel during the time frame 1970-2000 is shown in figure 11. The demand is expected to increase from 366 MM barrels to 1580 MM barrels per year by 2000, should JP be used exclusively. Based upon fuel properties, source of supply, price, environmental constraints and aircraft engine design requirements, future supersonic and hypersonic jet aircraft will probably require liquefied methane or hydrogen as preferred fuels. However, the aforementioned projections of JP fuel demand provide a valid basis for determining aircraft energy (Btu) demand regardless of fuel type. These demand projections assume a 6% increase per year for 1970-1980; 5% increase per year for 1980-1990; and 4% increase per year for 1990-2000. The resulting estimates seem to agree quite closely with the National Petroleum Council's forecast,[14] the U. S. Bureau of Mines' "high" demand forecast,[15] and the 1970 National Power Survey forecast.[16]

16(a)

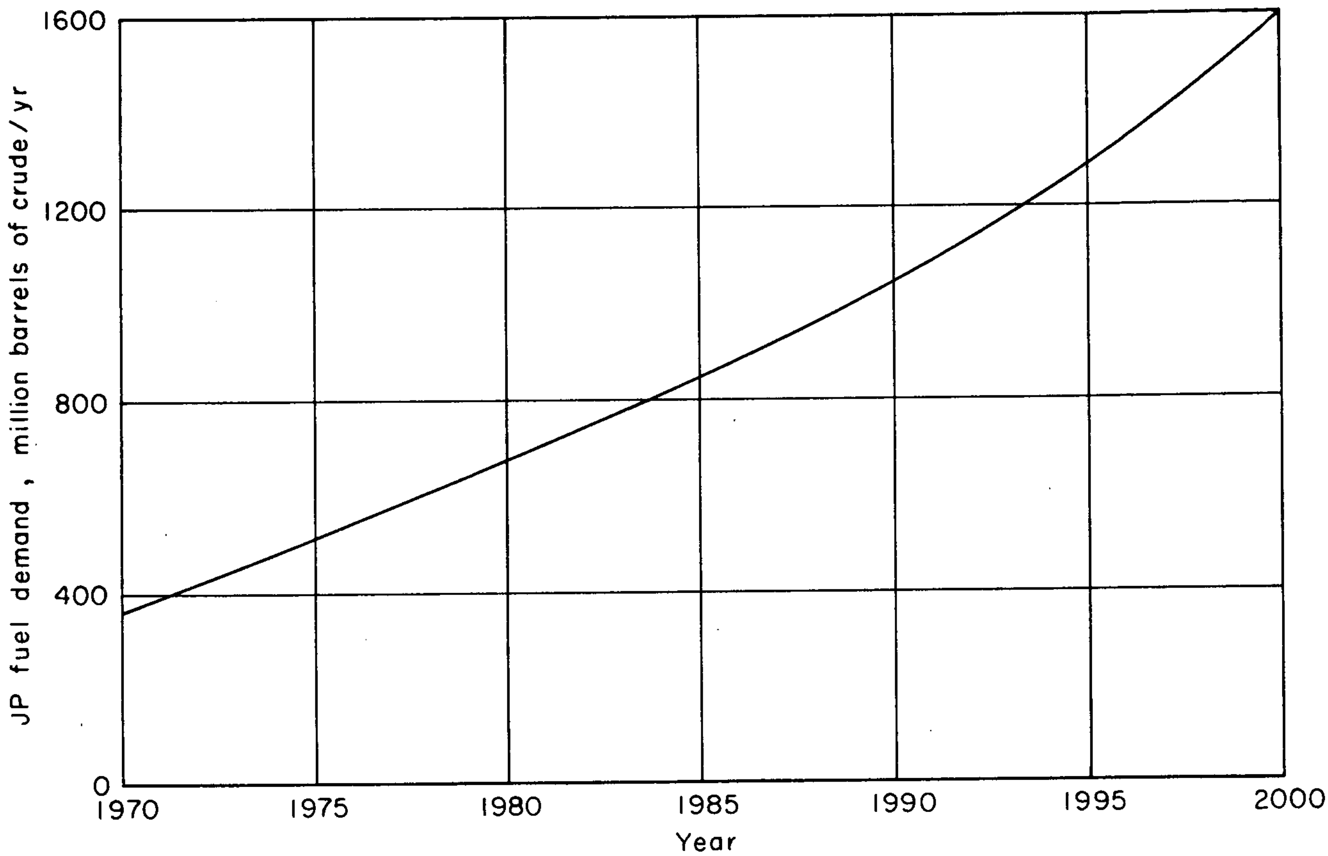

Figure 11.- U.S. JP Aircraft Fuel Demand Projection.

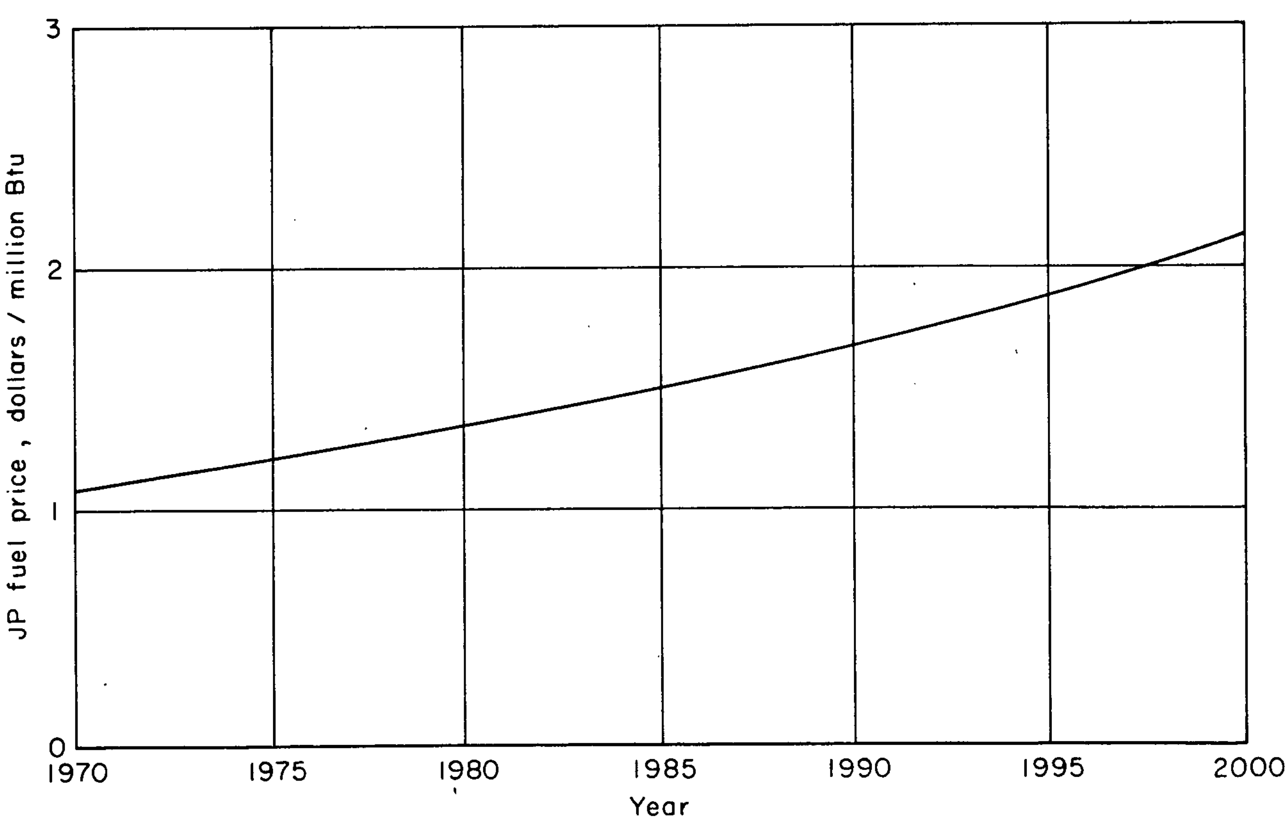

Figure 12.- U.S. JP Aircraft Fuel Price Projection.

The projected price of crude oil derived JP fuel shown in figure 12 is expected to increase from $1.08 per million Btu in 1970 to $2.11 per million Btu in 2000 (from $.145 per untaxed gallon, F.O.B. refinery to $.284 per gallon).

The waste-based synthetic fuel oil process described earlier is potentially capable of supplying half of the U. S. primary fossil fuel power demand by the year 2000. This will reduce the primary demand for natural crude oil and can be expected to ease the supply pinch on domestic crude, the preferred economic resource for JP fuel processing. The same thing may be said for coal liquefaction to a high-Btu-content, low-sulfur fuel oil. Synthetic fuel oil from either source may be upgraded to a satisfactory JP octane rating by catalytic hydrogenation. Requiring about 2000 cu ft H_2 per barrel of fuel oil feed, the hydrogen alone at current prices of $.25 per pound would add about 6.7 cents per gallon, or $2.80 per barrel of JP fuel produced. Since the current untaxed refinery price of JP fuel is about 15 cents per gallon, the upgrading of waste fuel oil would increase the base price of JP fuel at least 45%.

Liquid Methane Aircraft Fuel Economics.- Liquid methane as an aircraft turbine engine fuel offers many advantages over conventional JP fuel.[17,18] Among these are lower fuel cost and aircraft operating cost, lower gross aircraft weight, improved payload, range and velocity, improved handling and storage safety due to no toxicity, rapid evaporation and higher ignition temperature, and much lower decomposition product (5 orders of magnitude). The cooling values of both liquid methane and hydrogen are essential to higher Mach number, advanced aircraft performance, yet methane also offers similar advantages over JP in subsonic aircraft performance.

The cost ($ per million Btu) of liquid methane derived from domestic natural gas as a preferred economic source or from coal gasification has been estimated for the period 1970-2000. These costs (FOB the aircraft) are compared with JP fuel (FOB the refinery, due to wide variations in delivery contract pricing) in figure 13.

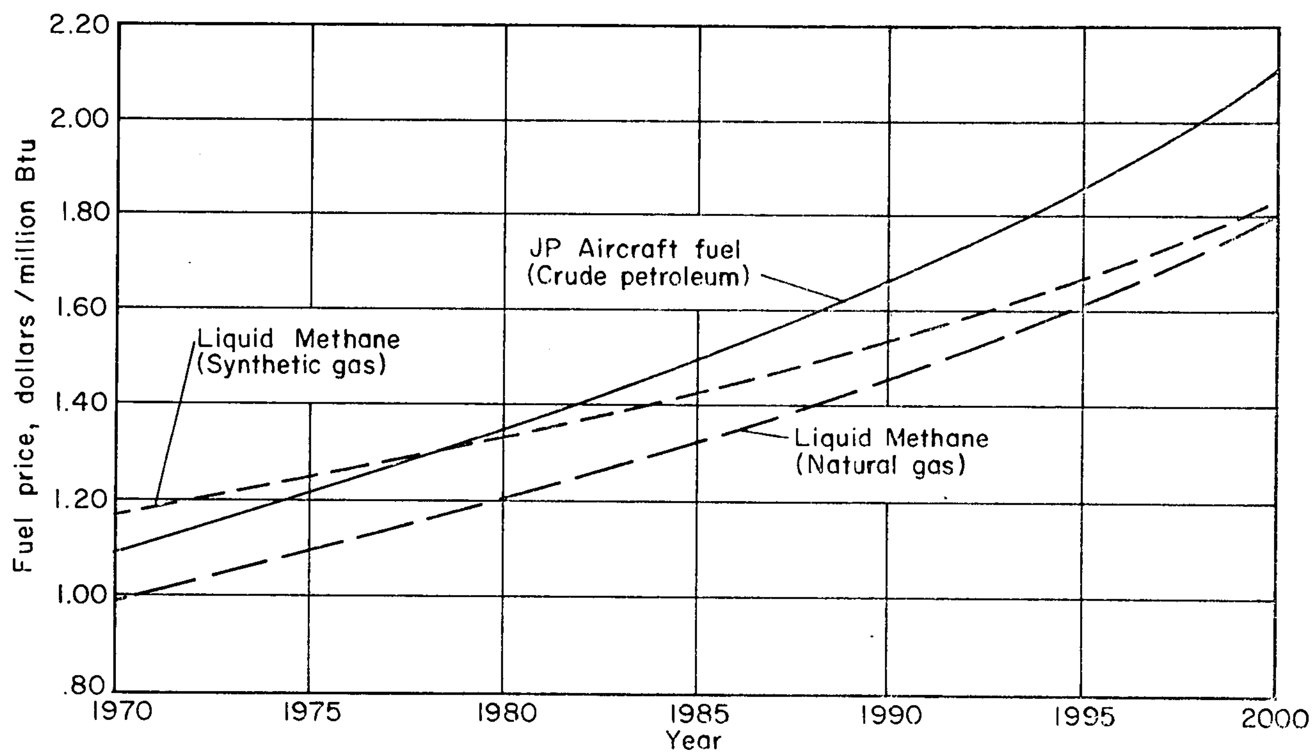

Figure 13.- Liquid Methane and JP Fuel Price Projections.

Liquid Propane Aircraft Economics.- Liquid propane offers many of the advantages[18] of methane as an aircraft fuel. It is superior to methane in density and onboard storage characteristics. However, it has three major disadvantages: appreciably higher cost, much greater decomposition product and greater safety and handling problems due to its density. It is only nominally superior to JP fuel, but costs about 50% more due to refinery price structure.

Liquid propane is derived principally from the distillation of crude petroleum[19] and from the fractionation of the product obtained from the catalytic and thermal cracking of light naphthas also obtained from crude distillation. The light naphtha feed stock is priced at about $.103 per gallon ($.745/MM Btu) versus coal at $.247/MM Btu. 9.24 gallons of light naphtha is required per million Btu's (1000 cubic feet) of propane produced, or a cost in feedstock alone of $0.952 per million Btu. Add to this cost general operating expenses of roughly $.200 per million Btu, liquefaction costs of $.310 per million Btu, and the resulting FOB refinery cost of liquefied propane is approximately $1.462 per million Btu. Figure 14 shows the projected price of propane for the period 1970-2000.

Liquid Hydrogen Economics.- The two principal processes employed in large-scale high-purity hydrogen production are methane-steam reforming and electrolysis of water. The feedstocks are respectively methane gas or water. Natural gas or coal synthesis gas supply, demand and price have been discussed extensively in the previous section; water, and particularly seawater, is for all practical considerations in infinite supply.

The price of liquid hydrogen by steam reforming ranges currently from $.085 to about $.200 per pound, $1.52 to $3.57 per million Btu.[20,21,22,23] These prices are highly dependent on plant size, capacity utilization, fuel cost, power cost and operating life of the plant. Though some reductions in fuel and power costs could be anticipated with the advent of mine mouth coal electrical generating and gasification plants, inflationary effects would tend to offset these savings. It is the author's opinion that $.08 per pound ($1.52 per million Btu) is a minimum price for liquid hydrogen via the steam reforming process.

The largest electrolytic hydrogen plant operating today produces 40 million standard cubic feet of hydrogen per day at a cost of $.137 per pound, $2.45 per million Btu.[24] Improvements in electrolytic cell efficiencies over the next 10 years promise a price of $0.10 per pound ($1.78 per million Btu). An assumed reduction in power costs due to nuclear facilities, particularly the fast breeder reactor, could result in electrolytic hydrogen at $0.08 per pound ($1.41 per million Btu); see calculations below and figure 15.

Present Electrolytic Hydrogen Costs* (1 Million Pounds/Day)

Cost Element		$/lb H_2
Power (25 kWh/lb H_2 @ $0.0026/kWh)	=	.068
Operating Expense	=	.020
Capital Charge (20% on $90 million inv.)	=	.049
Total Cost Per Pound		$.137 ($2.45/MM Btu)

Projected Electrolytic Hydrogen Costs* (1 Million Pounds/Day)

Cost Element	Fossil Fuel Electric $/lb H_2	Nuclear Electric $/lb H_2
Power (20 kWh/lb H_2 @ $.0026 & .0016/kWh)	.052	.032
Operating Expense	.020	.020
Capital Charge (20% on $50 million inv.)	.027	.027
Net Cost per Pound H_2	$.099 ($1.78/MM Btu)	$.079 ($1.41/MM Btu)

*1970 Dollars.

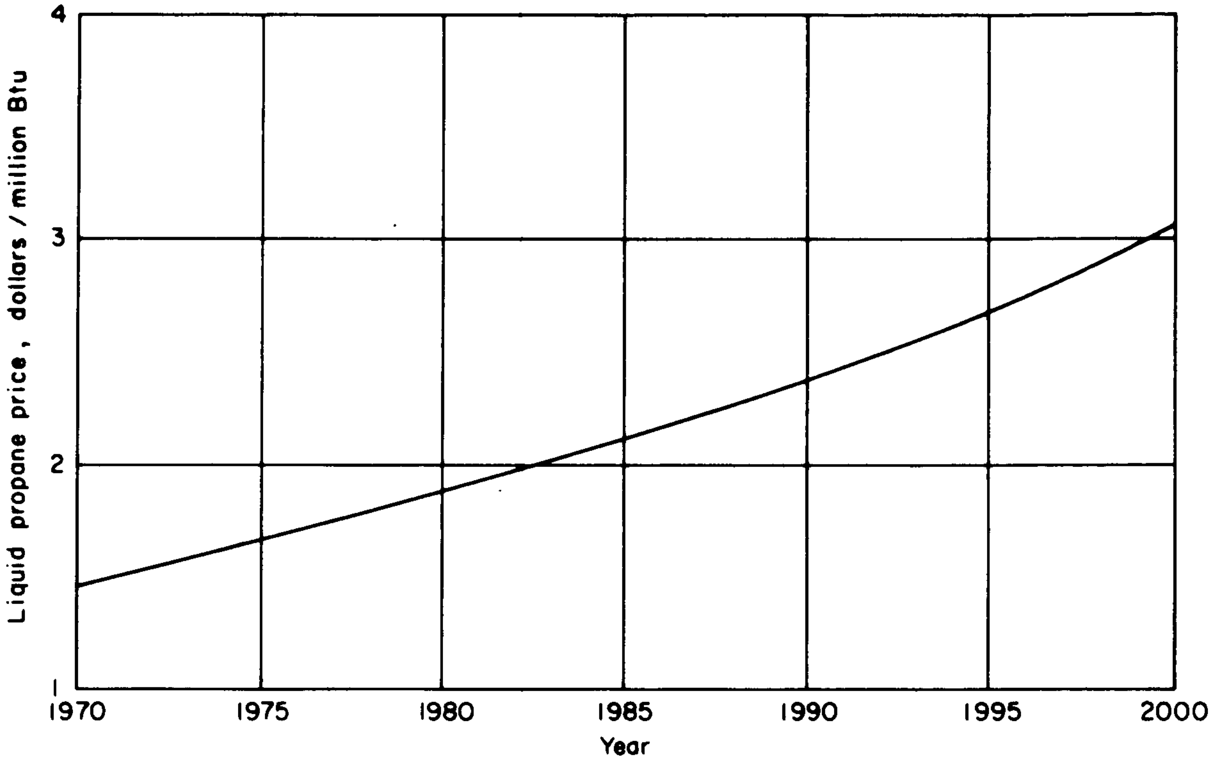

Figure 14.- U.S. Liquid Propane Price Projection.

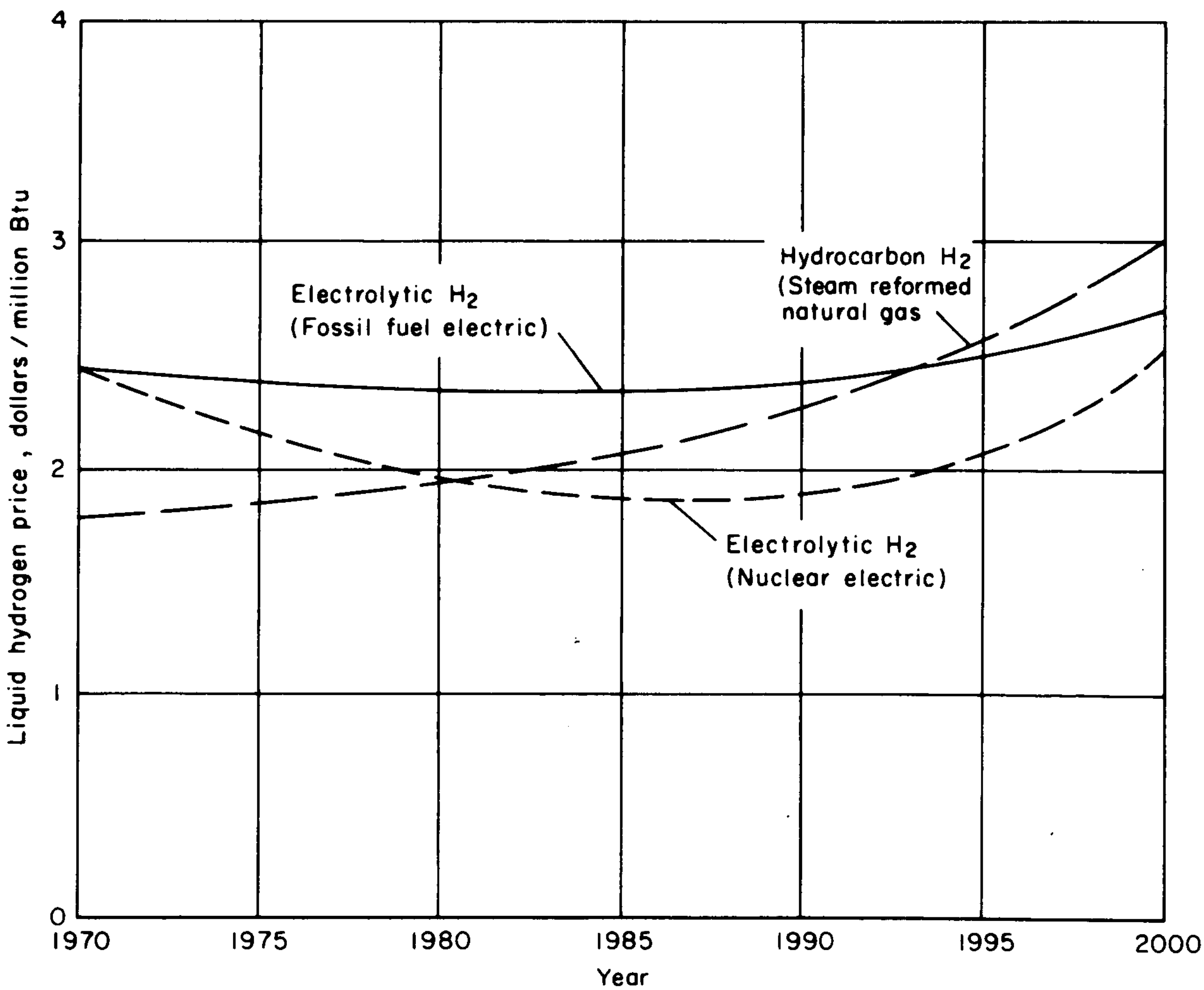

Figure 15.- U.S. Liquid Hydrogen Price Projections.

Availability of the four aircraft fuels evaluated in this study seems assured under a surprise-free future. Projected prices for these fuels (1970-2000) based on the least expensive resource and economic process are shown in figure 16; prices for the same fuels derived from secondary resources or via alternative technologies are illustrated in figure 17. Generally, aircraft fuel prices may be expected to double over the next 30 years, primarily due to inflationary influences. Ranking of fuel costs in dollars per million Btu indicates liquid methane as the least expensive followed closely by JP fuel, liquid hydrogen and liquid propane.

Pessimistic Resource/Fuel Scenarios

Foreign Oil and Gas Embargo.- Given an ample resource supply at current prices with existing processing methods, JP aircraft fuel (kerosene) and liquid propane are most economically derived in the United States from imported crude oil. Projections of U. S. domestic crude oil reserves and production for the period 1970-2000 indicate a decline from 11.3 million barrels per day (B/D) to about 9.3 million B/D. Concurrent with rising demand, U. S. crude oil imports may be expected to increase from 3.4 million B/D to 31.2 million B/D, or from 23% of demand to more than 77% of demand. Inasmuch as current exploration and discovery efforts seem to indicate that South American and Canadian oil is inadequate to meet more than present U. S. import demands, most of our future import crude oil must come from North African and Persian Gulf fields. Price negotiations in 1971 by these oil exporting countries (OPEC) with major U. S. and British oil companies resulted in sharply increased posted prices on crude oil; Libyan oil for example increased to the price of Texas crude ($3.45/barrel from $2.10/barrel).

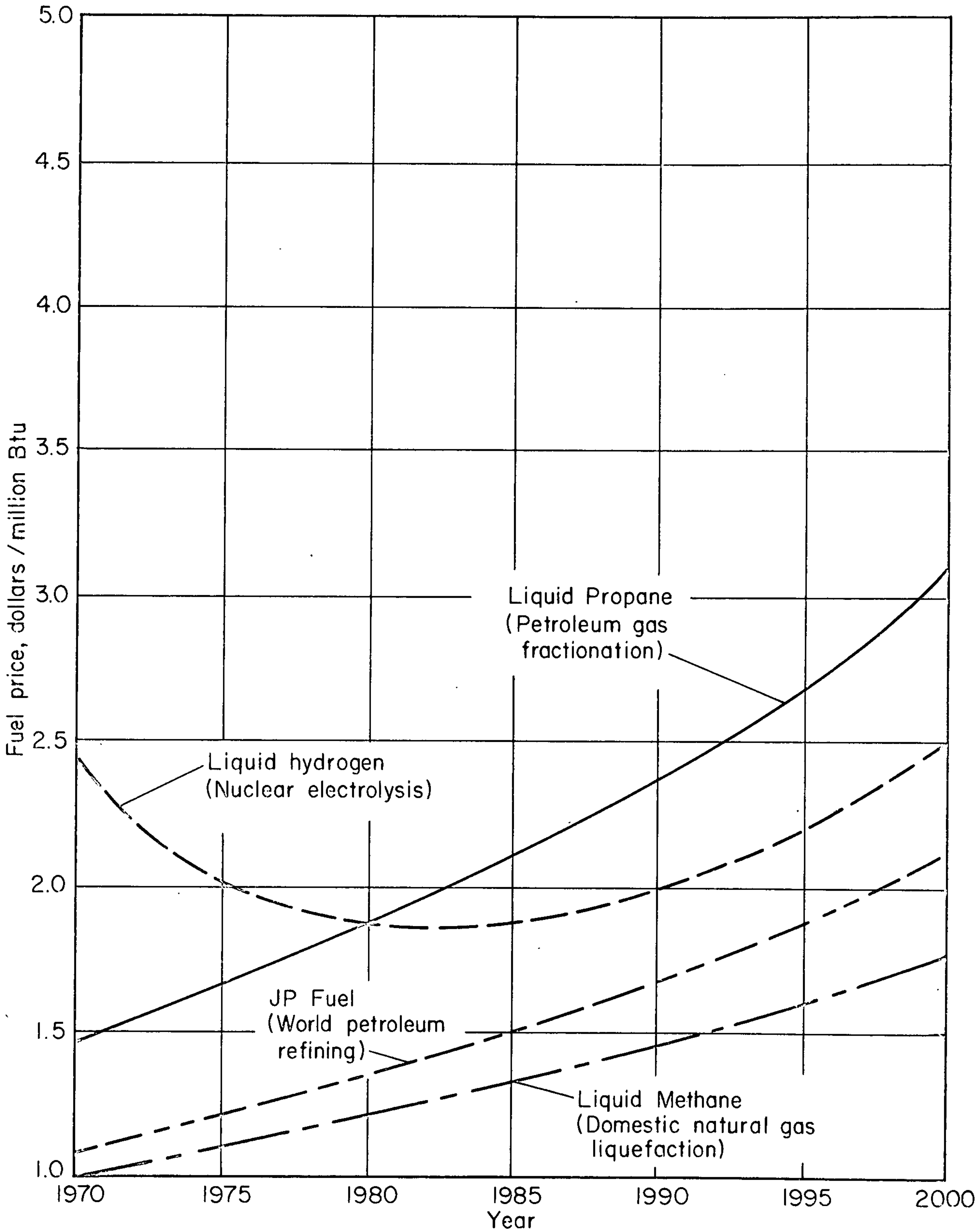

Figure 16.- Projected Prices of Four Aircraft Fuels Derived from Preferred Resource and Process.

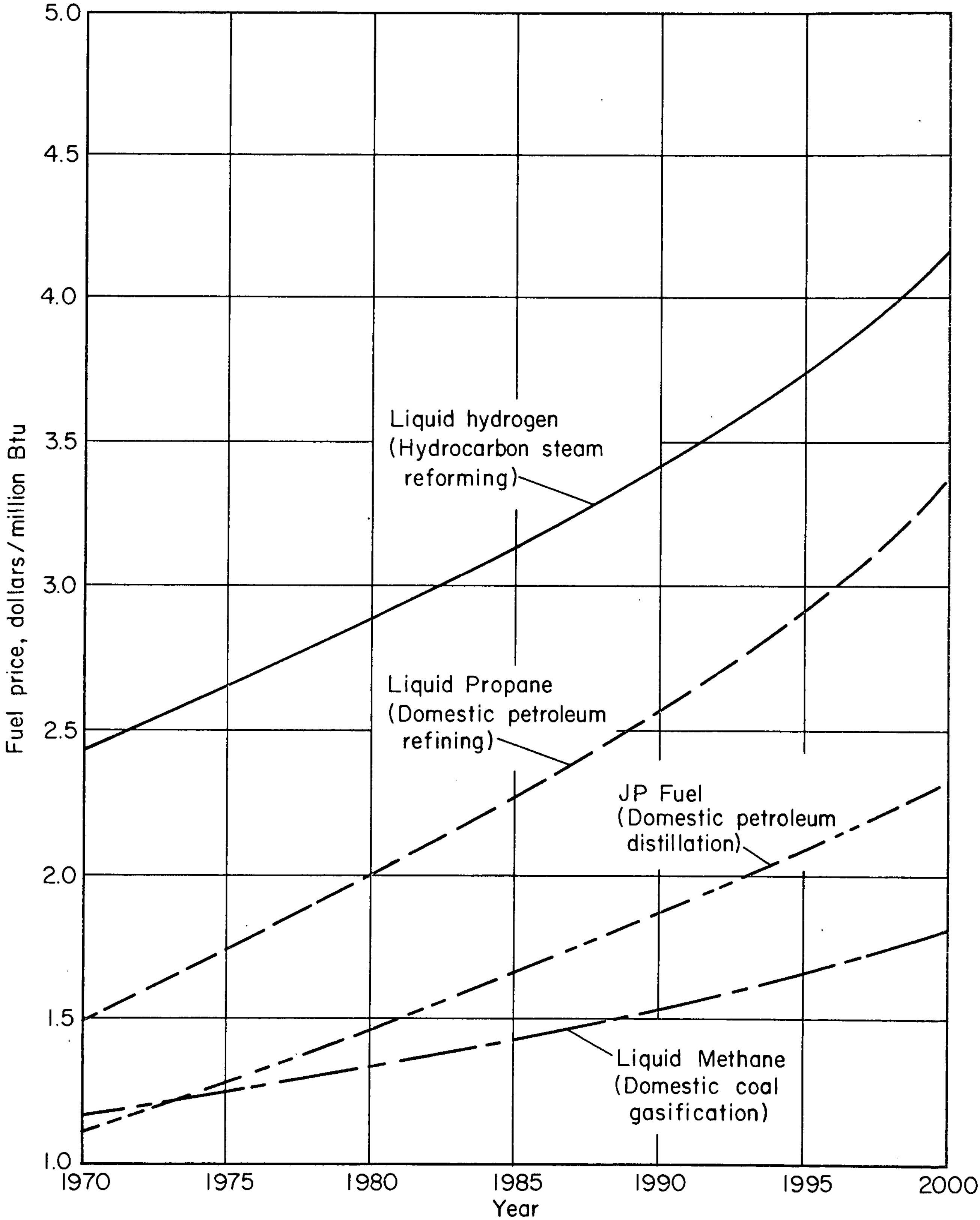

Figure 17.- Projected Price of Four Aircraft Fuels Derived from Secondary Resources and Processes.

As mentioned previously, the OPEC is a strongly militant organization sitting on the bulk of global oil reserves; the OPEC member nations are becoming increasingly nationalistic and anti-West. Exploration, development, pipeline transportation, shipping and port facilities in these nations have resulted primarily from Western capital investment, which, if nationalized would constitute a major loss to U. S. oil companies. Nationalization of these properties would tend to discourage or negate further Western investment, resulting in curtailment in future supply of crude oil. At the least, oil prices can be expected to soar to a level commensurate with alternative product and process pricing.

Fuel oil can be made from coal and from cellulosic waste. Hydrogenating this synthetic fuel oil yields a satisfactory JP fuel at a cost of about 6.7 cents per gallon ($2.80 per barrel). This 45% increase in 1970 dollars over current crude oil derived JP fuel would tend to establish an upper limit on import oil equivalent value of about $6.25 per barrel. JP fuel produced from imported crude oil at this price (or from synthetic domestic fuel oil) would be priced at $1.95 per million Btu versus present pricing of $1.08 per million in 1970 dollars. Lead time to open additional U. S. coal fields and to construct coal/synthetic oil and hydrogen processing plants of sufficient capacity to absorb U. S. import oil demand is estimated at 3-5 years. Unless the U. S. can anticipate by 3-5 years either a cut-off or radical price increase in foreign oil, there will be a critical supply problem, price problem, or both, associated with JP aircraft and liquid propane fuels. Figure 18 projects the price consequence of this scenario on JP and liquid propane aircraft fuel prices should this event occur in 1975.

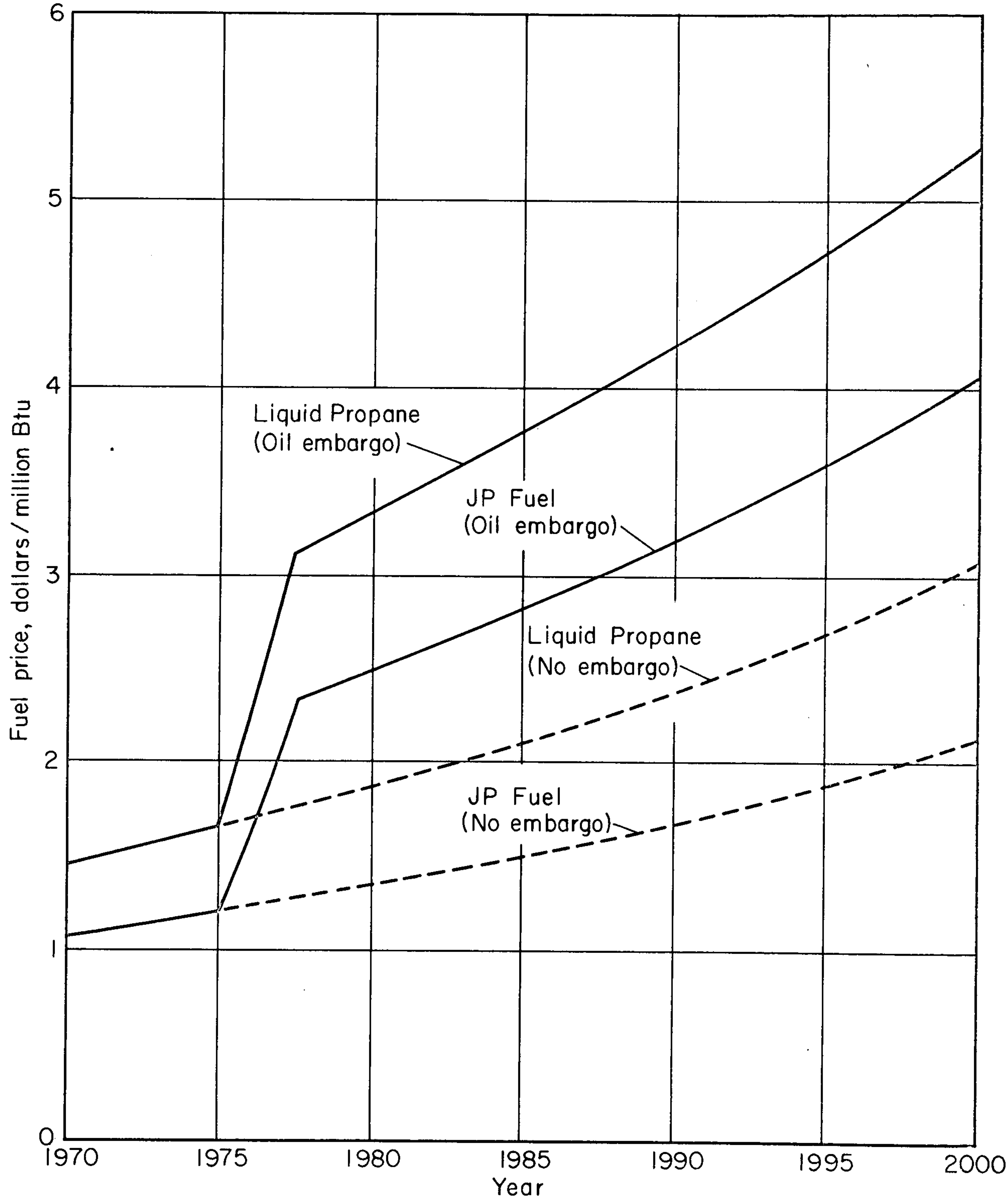

Figure 18.- Cost Effect of Foreign Oil Embargo on U.S. JP and Liquid Propane Fuels.

Similarly, projected estimates of U. S. natural gas demand over the period 1970-2000 indicate an increasing reliance on import liquid natural gas (LNG), principally from Algeria. Since liquid methane is most economically extracted from natural gas, and natural gas steam reforming is the presently preferred process for obtaining liquid hydrogen, the United States possibly faces a future price rise in foreign LNG based liquid methane and hydrogen similar to that described for JP and liquid propane aircraft fuels. Fortunately, coal gasification employing U. S. domestic coal provides a synthetic gas rich in methane at a lower cost per million Btu than present LNG import costs. The sole problem would be lag time in developing additional U. S. productive coal gasification capacity should the U. S. fail to anticipate an LNG foreign embargo.

<u>Environmental and Safety Constraints</u>.- Current estimates of the cost of environmental protection in U. S. coal mining and reclamation technology fall between $0.20 and $0.40 per ton of coal (4-8% increase on 1970 average price). The impact of the 1969 Coal Mine Health and Safety Act has yet to be fully evaluated, but one estimate has placed the increased cost at $1.50 to $2.00 per ton (30-40% increase on the 1970 minemouth price) with a commensurate 20% reduction in production. Therefore, current U. S. environmental and safety constraints on coal mining may be expected to increase domestic coal prices 35 to 50%. Subsequent air quality requirements for removal of SO_2 stack gases resulting from burning or processing high sulfur content coal or oil may be expected to add a further sulfur-removal cost to coal and oil prices.

Since much of the United States' new oil and gas resources are located either off-shore (continental shelf) or in Alaska, environmental considerations will undoubtedly result in higher production costs in order to prevent oil spill water pollution. Increased oil costs resulting from future pollution control measures and lowered productivity may be assumed to be equivalent to those costs already experienced in U. S. coal production. If so, the price of domestic crude oil may increase 50% over the 1970 price for Texas crude of $3.40 per barrel. This would have an identical effect on the price of JP and liquid propane aircraft fuels as shown in the previous scenario. Inasmuch as the coal prices used in domestic coal gasification calculations included these environmental and safety costs, the previously projected prices for liquid methane and hydrogen remain unchanged.

Environmentally imposed restrictions on the licensing and construction of U. S. nuclear electric power plants may indeed result in domestic coal and imported oil and gas absorbing a larger share of future U. S. energy production. The result of this course of action would be to bring about a more immediate supply/demand pricing crisis in fossil fuels, which in turn would result in radical increases in aircraft fuel prices of the order of 50-100%.

CONCLUSIONS

This study examined the economics of four future aircraft fuels--JP fuel, liquid hydrogen, liquid methane and liquid propane--as to production, comparative resource availability, demand and price stability over the period 1970-2000. 1970 JP aircraft fuel demand consumed 7% of annual U. S. petroleum supply. Future JP fuel demand was projected to consume 10% of future petroleum supply.

Despite an assumption that nuclear generating stations may provide up to 25% of U. S. energy requirements by the year 2000, projections of our oil and gas needs to satisfy the remaining 75% energy demand[1] indicate that the nation will be forced to import as much as 75% of its oil and 70% of its gas. The implications of this degree of future reliance on foreign supplies of primary fossil fuels are clear with respect to national security, balance of trade and energy costs, including the future cost of the aircraft fuels reviewed in this study.

This future reliance on import fossil fuels may be avoided through a redirection of U. S. public and private policies concerning the regulation of resource prices, the availability and choice of alternative technological processes, the direction of major capital commitment, the degree of risk the nation is willing to accept (e.g., nuclear versus conventional), the ecological balance desired and afforded and its desire and ability to conserve these resources and to use them more efficiently.

Availability of the four aircraft fuels evaluated in this study seems assured. Projected prices for these fuels (1970-2000) may be expected to double over the next 30 years, primarily due to inflationary influences. Ranking of fuel costs in dollars per million Btu indicates liquid methane to be the least expensive followed closely by JP fuel, liquid hydrogen and liquid propane.

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